ORIGINAL

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DEPARTMENT OF THE AIR FORCE
HEADQUARTERS AIR FORCE LEGAL OPERATIONS AGENCY

Re: IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN

IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY

Dear Arizona Corporation Commission:

On behalf of Federal Executive Agencies (FEA), I have enclosed a copy of FEA's Direct Testimony of Michael P. Gorman and Brian C. Andrews for docket#s E-01345A-16-0036 and E-01345A-16-0123. In addition, workpapers of Michael P. Gorman will sent under a separate cover.

Please let me know if you have any questions regarding this matter.

Arizona Corporation Commission
DOCKETED
DEC 21 2016
DOCKETED BY GB

Respectfully,

EBONY M. PAYTON
Paralegal for FEA

RECEIVED
AZ CORP COMMISSION
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CERTIFICATE OF SERVICE

Service List for Docket No. E-01345A-16-0036
E-01345A-16-0123

I HEREBY CERTIFY that a true and correct copy has been furnished by electronic mail (e-mail) and/or U.S. Mail this 21st day of December 2016 to the following:

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BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN)	**DOCKET NO. E-01345A-16-0036**
IN THE MATTER OF FUEL AND PURCHAED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY)	**DOCKET NO. E-01345A-16-0123**

Direct Testimony and Exhibits of

Brian C. Andrews

On behalf of

Federal Executive Agencies

December 21, 2016

BAI

BRUBAKER & ASSOCIATES, INC.

Project 10268

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	**DOCKET NO. E-01345A-16-0036**
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Table of Contents to the Direct Testimony of Brian C. Andrews

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)	**DOCKET NO. E-01345A-16-0036**
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Direct Testimony of Brian C. Andrews

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am testifying on behalf of the Federal Executive Agencies ("FEA"), consisting of certain agencies of the United States government, which have offices, facilities, and/or installations in the service area of Arizona Public Service Company ("APS" or "Company"), from whom they purchase electricity and energy services.

Q WHAT IS THE SUBJECT MATTER OF YOUR DIRECT TESTIMONY?

A My testimony will address APS's proposed changes to the depreciation rates for the Cholla Power Plant. My silence in regard to any issue should not be construed as an endorsement of APS's position.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are summarized as follows:

1. APS has overstated its depreciation rates for the Cholla Power Plant because it has shortened the life span of this plant. The resulting depreciation rates produce an excessive amount of depreciation expense and overstate the test year revenue requirement.

2. APS has not yet determined its plans for the Cholla Power Plant after 2025. Current ratepayers should not be burdened by the proposed accelerated capital recovery of the Cholla Power Plant until a firm decision has been made for the future plans of this plant.

3. APS should continue to use the existing depreciation rates for the Cholla Power Plant until it has made an official determination of its plans for the Cholla Power Plant after 2025.

4. This adjustment reduces the test year depreciation expense and, thus, the revenue requirement by $23.9 million.

II. Book Depreciation Concepts

Q PLEASE EXPLAIN THE PURPOSE OF BOOK DEPRECIATION ACCOUNTING.

A Book depreciation is the recognition in a utility's income statement of the consumption or use of assets to provide utility service. Book depreciation is recorded as an expense and is included in the ratemaking formula to calculate the utility's overall revenue requirement.

Book depreciation provides for the recovery of the original cost of the utility's assets that are currently providing service. Book depreciation expense is not intended to provide for replacement of the current assets, but provides for capital recovery or return of current investment. Generally, this capital recovery occurs over the average service life of the investment or assets. As a result, it is critical that appropriate average service lives be used to develop the depreciation rates so no generation of ratepayers is disadvantaged.

In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is simply the scrap or reused value less the removal cost of the asset being depreciated. Accordingly, a utility will also recover the net salvage costs over the useful life of the asset.

Q ARE THERE ANY DEFINITIONS OF DEPRECIATION ACCOUNTING THAT ARE UTILIZED FOR RATEMAKING PURPOSES?

A Yes. One of the most quoted definitions of depreciation accounting is the one contained in the Code of Federal Regulations:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption of prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and

> tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities." (Electronic Code of Federal Regulations, Title 18, Chapter 1, Subchapter C, Part 101)

Effectively, depreciation accounting provides for the recovery of the original cost of an asset, adjusted for net salvage, over its useful life.

Q WHAT METHOD, PROCEDURE AND TECHNIQUE WERE USED TO CALCULATE THE PROPOSED DEPRECIATION RATES FOR APS?

A The proposed depreciation rates were calculated using the straight line method, the vintage group procedure and the remaining life technique. Under this method, procedure and technique of developing depreciation rates, the unrecovered cost of plant in service is adjusted for the cost of net salvage, and is recovered over the remaining life of the asset or group of assets. At the end of the useful life, the asset is fully depreciated.

III. Cholla Power Plant

Q PLEASE BRIEFLY DESCRIBE THE CHOLLA POWER PLANT.

A The Cholla Power Plant is currently a three-unit, 767 MW coal-fired power plant located in northeastern Arizona. APS operates the plant and owns all of Units 1 (116 MW) and 3 (271 MW). Unit 4 with a capacity of 380 MW is owned by PacifiCorp. Additionally, APS owns Cholla Unit 2, a 260 MW unit, which was retired on October 1, 2015.

Q **WHEN APS FILED ITS 2014 IRP, WHAT WERE ITS PLANS FOR THE CHOLLA POWER PLANT?**

A On April 1, 2014, APS filed its 2014 Integrated Resource Plan ("IRP"). At that time, the selected portfolio called for continued operation of all of its coal plants, including Cholla Units 1-3. Exhibit BCA-1 contains Attachment F.1(a)(2) from the 2014 IRP. This table shows APS's selected portfolio, which indicates that APS expected to use 1,932 MW of its existing coal resources from 2014 through the study period in 2029. Under this portfolio, approximately 24.5% of APS's 2029 energy mix would be from coal-fired generation.

Q **HOW DID THOSE PLANS CHANGE WITH THE 2014 IRP SUPPLEMENT?**

A Just five and half months later, on September 14, 2014, APS filed its 2014 IRP Supplement. In this IRP Supplement, APS presented the Commission with a change to its Selected Portfolio. APS changed its selected portfolio to the Managed Coal Strategy. The Managed Coal Strategy included the closure of Cholla Unit 2 in April 2016 and the decision that no coal would be burned at Cholla Units 1 and 3 after the expiration of a coal agreement in the mid-2020s. The Managed Coal Strategy would reduce the 2029 coal capacity to 1,285 MW, down from 1,932 MW with the April 2014 selected portfolio. Additionally, the percentage of energy generated by coal would be reduced to 16.9%, down from 24.5%

Q **WHAT WAS APS'S REASONING BEHIND THE CHANGE IN ITS CHOICE OF RESOURCE PORTFOLIOS?**

A It appears largely driven by environmental regulations. The second sentence of the document states, *"Because of changes in the regulatory environment and on-going* *discussions with the federal Environmental Protection Agency, the Arizona Department of Environmental Quality and the owner of Cholla Unit 4, PacifiCorp, APS now supplements and amends its IRP to select a different portfolio of resources than the Selected Portfolio ("April 2014 Selected Portfolio") previously chosen in its April filing."* It later goes on to state at page 3 lines 5-6, "*Given APS's discussions with environmental regulators and its plans for the future, APS's choice of portfolios must change.*"

Q DOES THE MANAGED COAL STRATEGY SELECTED WITH THE 2014 IRP SUPPLEMENT CONTAIN FIRM PLANS FOR CHOLLA UNITS 1 AND 3?

A No. The only firm plans were for Cholla Unit 2. The managed coal strategy called for the closure of Cholla Unit 2 on or before April 1, 2016 and that Units 1 and 3 would not burn coal after the mid-2020s. In fact, APS concludes the IRP supplement by stating that the Managed Coal strategy provides APS flexibility with the EPA to preserve the current status of Cholla Units 1 and 3 through the mid-2020s, while still keeping open the option of gas conversion.

Q HAS APS RETIRED CHOLLA UNIT 2?

A Yes. Cholla Unit 2 was retired on October 1, 2015

Q WHAT ACCOUNTING TREATMENT HAS BEEN AFFORDED TO APS FOR CHOLLA UNIT 2?

A As is discussed by APS witness Ms. Blankenship on page 24 of her direct testimony, the unrecovered investment due to the early retirement of Cholla Unit 2 has been transferred from plant in service to a regulatory asset. This regulatory asset includes to the remaining net book value of Cholla Unit 2 and the accrual of remaining removal costs for final retirement and dismantlement. APS is proposing to amortize this regulatory asset through 2033, its previously estimated retirement year.

Q IN THE INSTANT PROCEEDING, WHAT IS APS PROPOSING TO DO WITH THE REMAINING CHOLLA UNITS IN TERMS OF DEPRECIATION?

A Dr. White has conducted a depreciation study on behalf of APS. On page 80 of Attachment REW-2DR, it shows that the retirement dates for Cholla Units 1 and 3, as well as the common facilities have been reduced to 2025. The currently approved depreciation rates for Cholla Unit 1 were calculated assuming a retirement date of 2028. For the common facilities and Unit 3, the currently approved depreciation rates were calculated assuming a retirement date of 2035. By reducing the retirement date to 2025, APS is increasing the annual depreciation expense for this plant by $23.9 million and is assuming the plant will be dismantled in 2025.

Q ARE APS'S PROPOSED DEPRECIATION RATES FOR CHOLLA UNITS 1 AND 3 REASONABLE?

A No. APS's proposed depreciation rates for Cholla Units 1 and 3, as well as the common facilities, are not reasonable. APS does not yet know if the Cholla Power Plant will be retired or converted to natural gas after the mid-2020s. The depreciation rates being proposed for the Cholla Power Plant do not match reality. The proposed depreciation rates for the Cholla Power Plant assume complete retirement and dismantlement in 2025. Aside from its decision not to burn coal in Cholla Units 1 and 3 beyond 2025, it continues to consider the economics of its coal fleet and the critical importance of fuel diversity as it evaluates the best overall resource strategy for the benefit of its customers.[1]

Q DOES APS'S PRELIMINARY 2017 IRP SHOW DEFINITE PLANS IN PLACE FOR THE REMAINING CHOLLA UNITS?

A No. APS filed its preliminary 2017 IRP on September 30, 2016. APS has yet to commit to a plan for Cholla Units 1 and 3 after the mid-2020s. In a discussion on page 7 of 36 of this document, which discusses APS's coal strategy, it states that the outlook for the Company's coal-fired assets is more uncertain (relative to its nuclear and natural gas fleet), and that key decisions remain ahead for the Cholla Power Plant.

Q IF THE REMAINING TWO CHOLLA UNITS ARE REPOWERED TO RUN ON NATURAL GAS, CAN EXISTING INFRASTRUCTURE BE UTILIZED?

A Yes. However, the amount of existing infrastructure that can be re-used must be determined through a detailed study. There are multiple types of repowering that can be utilized; the boiler can be modified for natural gas combustion rather than coal, or the boiler can be replaced with a combustion turbine and a heat recovery steam generator. In any case, it is likely that the existing generator, steam turbine, and condensers can be used to operate on natural gas after 2025. A detailed study will determine which option is most economically feasible. I have included as Exhibit BCA-2 a white paper that discusses this type of study and some available coal to natural gas conversion options that are available.[2]

[1]Direct Testimony of Daniel T. Froetscher at page 8 line 24 through page 9 line 2.
[2]This white paper is a copyright protected product belonging to Babcock & Wilcox Power Generation Group, Inc. It is available in the public domain through the Babcock & Wilcox website at www.babcock.com/library/Documents/MS-14.pdf.

Q IF THE EXISTING INFRASTRUCTURE AT THE CHOLLA POWER PLANT IS CONTINUED TO BE USED FOR NATURAL GAS OPERATION, WOULD IT BE REASONABLE TO ASK CURRENT RATEPAYERS TO PAY FOR GREATER ANNUAL DEPRECIATION EXPENSE BASED ON THE ASSUMPTION THAT THE ENTIRE PLANT WILL BE RETIRED AND DISMANTLED IN 2025?

A No. There is too much uncertainty around the Cholla Power Plant at this time to force current ratepayers to pay an additional $23.9 million in annual depreciation expense for this plant. If the Cholla Power Plant is repowered for natural gas, a change to the depreciation rates should account for any equipment that will be reused, as well as reduced dismantlement costs and accurate retirement dates. Furthermore, APS's decision to shut down the Cholla Power Plant early came just five and a half months after its initial 2014 IRP decision to keep all of its coal resources operating at least through 2029. Over the next few months, environmental regulation uncertainty should be clarified with the beginning of a new administration in Washington. There is still a reasonable possibility that the Cholla Power Plant could continue to burn coal after 2025.

Q IS IT A REASONABLE ASSUMPTION THAT THE INCOMING ADMINISTRATION COULD IMPACT THE FUTURE OF COAL GENERATION, ESPECIALLY CONCERNING THE CLEAN POWER PLAN?

A Yes. It appears that the incoming administration may have a vastly different opinion on environmental regulations relative to the current administration.

Q WHAT IS YOUR RECOMMENDATION FOR THE DEPRECIATION RATES FOR THE REMAINING CHOLLA UNITS?

A I recommend that the existing depreciation rates for the Cholla Power Plant remain in effect. These existing rates assume that Unit 1 will retire in 2028 and Unit 3, as well as the common facilities, will retire in 2035. These depreciation rates should not change until after APS has made an official determination of its plans for Cholla Units 1 and 3.

Q WHAT IS THE RESULT OF YOUR RECOMMENDATION ON APS'S ANNUAL DEPRECIATION EXPENSE AND ITS TEST YEAR REVENUE REQUIREMENT?

A By not changing the depreciation rates for the Cholla Power Plant, APS's annual depreciation expense and, thus, the test year revenue requirement is reduced by $23.9 million.

Q HOW DID YOU DETERMINE THIS IMPACT?

A In response to FEA Data Request 1.6, APS provided a workbook that shows the impact on revenue requirement due to a change in depreciation rates. Using a slightly modified version of this workbook, if the Cholla Power Plant depreciation rates are not changed, the pro forma adjustment for the 2015 Depreciation Study is reduced to $52.074 million, down from $75.989 million which is shown as adjustment 30 of Schedule C-2, page 10 of 16, and sponsored by Ms. Blankenship. This is shown in Exhibit BCA-3.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Electrical Engineering from the Washington University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I have also received a Master of Science Degree in Applied Economics from Georgia Southern University.

I have attended training seminars on multiple topics including class cost of service, depreciation, power risk analysis, production cost modeling, cost-estimation for transmission projects, transmission line routing, MISO load serving entity fundamentals and more.

Additionally, I am a certified Engineer Intern in the State of Missouri, and I am a member of the Society of Depreciation Professionals.

As a consultant at BAI, and as an Associate Consultant and Assistant Engineer before that, I have been involved with several regulated and competitive electric service issues. These have included book depreciation, fuel and purchased power cost, transmission planning, transmission line routing, resource planning including renewable portfolio standards compliance, electric price forecasting, class cost of service, power procurement, and rate design. This has involved use of power flow, production cost, cost of service, and various other analyses and models to address these issues, utilizing, but not limited to, various programs such as STRATEGIST, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United States Department of Energy/Bonneville Power Administration's Corona and Field Effects ("CAFÉ") Program. Additionally, I have received extensive training on the PLEXOS Integrated Energy Model.

BAI was formed in April 1995. BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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2014 INTEGRATED RESOURCE PLAN

APRIL 2014 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

SELECTED PORTFOLIO
LOADS & RESOURCES - MW CONTRIBUTION AT PEAK

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
1	LOAD REQUIREMENTS																
2	APS Peak Demand	7,146	7,292	7,573	7,881	8,180	8,481	8,772	9,071	9,373	9,671	9,965	10,250	10,558	10,860	11,167	11,477
3	Annual Load Growth %		2.0%	3.9%	4.1%	3.8%	3.7%	3.4%	3.4%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%	2.8%	2.8%
4	Reserve Requirements	978	976	993	1,016	1,039	1,063	1,093	1,196	1,238	1,275	1,310	1,349	1,386	1,426	1,465	1,505
5	Total Load Requirements	8,124	8,268	8,566	8,897	9,219	9,543	9,864	10,268	10,610	10,946	11,276	11,609	11,945	12,286	12,632	12,982
6	EXISTING RESOURCES																
7	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
8	Coal	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
9	Natural Gas	5,612	5,536	4,879	4,229	4,009	4,009	3,412	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932	2,932
10	Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
11	Combustion / Steam Turbines	1,254	1,254	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
12	PacifiCorp Seasonal Exchange	480	400	480	480	480	480	480	0	0	0	0	0	0	0	0	0
13	Tolling Agreements	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0	0	0
14	Market/Call Options / Hedges /AG-1	820	848	187	37	37	37	0	0	0	0	0	0	0	0	0	0
15	Renewable Energy	476	463	463	463	464	464	453	444	435	424	416	417	418	401	401	402
16	Wind	55	55	55	55	55	55	55	55	55	55	55	55	55	37	37	37
17	Solar	396	388	383	383	383	383	373	363	355	356	349	349	350	351	352	352
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
19	Biomass/Biogas	15	16	16	16	16	16	16	16	16	3	3	3	3	3	3	3
20	Total Existing Resources	9,158	9,084	8,420	7,770	7,550	7,550	6,843	6,454	6,446	6,433	6,426	6,426	6,427	6,410	6,411	6,412
21	CUSTOMER RESOURCES																
22	Energy Efficiency	109	287	434	594	738	877	1,008	1,096	1,130	1,174	1,230	1,264	1,307	1,351	1,396	1,447
23	Distributed Energy	45	53	74	86	98	109	119	133	155	181	203	224	237	245	253	261
24	Demand Response	21	21	28	28	26	26	51	76	126	151	176	175	200	225	250	275
25	Existing DR	21	21	26	25	25	25	26	26	26	26	26	0	0	0	0	0
26	Future DR	0	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
27	Total Customer Resources	174	350	535	706	862	1,013	1,178	1,305	1,412	1,507	1,610	1,663	1,744	1,821	1,899	1,983
28	FUTURE RESOURCES																
29	Natural Gas	0	0	0	364	750	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
30	CCs/CTs	0	0	0	0	510	1,010	1,714	2,418	2,622	2,826	3,030	3,695	3,695	3,797	4,001	4,205
31	Short-Term Market Purchases	0	0	0	364	240	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	32	57	57	57	57	111	154	189	267	295	318	322	342	421	425
33	Wind	0	0	0	0	0	0	0	0	0	0	0	18	18	33	33	33
34	Solar	0	32	57	57	57	57	111	154	189	192	220	225	229	234	238	242
35	Geothermal	0	0	0	0	0	0	0	0	0	75	75	75	75	75	150	150
36	Total Future Resources	0	32	57	420	807	1,067	1,825	2,572	2,811	3,093	3,325	4,013	4,017	4,139	4,422	4,630
37	TOTAL RESOURCES	9,340	9,487	9,012	8,897	9,219	9,650	9,846	10,331	10,668	11,033	11,361	12,102	12,188	12,371	12,732	13,025

White Paper
MS-14

Natural Gas Conversions of Existing Coal-Fired Boilers

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Natural Gas Conversions of Existing Coal-Fired Boilers

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Abstract

Electric utilities are always searching for ways to minimize costs, improve availability and reduce emissions. Recent changes in the price of natural gas have made that fuel economically attractive, with the added benefit of reduced emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x) and carbon dioxide (CO_2). For those utilities with existing coal-fired units, conversion from coal firing to natural gas firing might be an option worth considering.

This paper will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision.

Rationale for Considering Fuel Switching

The first step in the process is to identify the forces that drive the decision to convert from coal to gas. The key forces are regulatory (both in terms of emissions and as an offset for a new unit), fuel costs, the age of the plant and the need for plant output.

Regulatory forces are currently in a state of flux, with a wide range of proposed rules and legislative efforts that could have a far-reaching impact on coal-fired operation. What appears likely is that some form of CO_2 controls will be enacted in the near future. Those controls could be part of a cap-and-trade system (similar to previous allowance programs for SO_2 and NO_X) or they might take the form of gradual reductions to meet increasingly stricter goals. Regardless of the final form, the industry is reasonably certain that there will be some additional controls placed on power plant owners. Utilities must also factor in the future need for electrical power generation – either because of market demand projections or to replace a unit that might be approaching the limit of its useful service. There also may be regulatory issues to evaluate, such as New Source Review and offsets for other emissions regulated by state and federal laws.

The price of natural gas has recently become more attractive as a baseload fuel due to additional supply and reduced demand from general industry. There are many different projections of where gas prices might be in the near future, all of which are based on the forces of supply and demand. The current price of natural gas is relatively low and stable compared to previous years. Utilities should be aware that natural gas prices are much more sensitive than coal prices to short term changes in supply and demand. While current economic conditions favor natural gas usage, Babcock & Wilcox Power Generation Group, Inc. (B&W PGG) strongly advises its customers to evaluate potential price volatility as a key component in the decision making process.

A plant may be considered for fuel switching based on its age and how close it would be to a possible retirement or major rebuild. The timing for fuel switching may be ideal if the boiler in question is already under consideration for major projects like superheater replacement, burner modifications, air system changes and/or the addition of back-end emissions control equipment. B&W PGG can assist in comparing the costs and benefits of different scenarios to help make the best decision based on the specific needs of the plant.

One of the other key factors to consider is the need for plant output, including a potential for de-rate and/or increased turn-down capability. A unit's continued usefulness might involve its ability to operate or be on standby during periods of low load.

As utilities look at their long-term forecasts, plants that operate efficiently and with high availability will play a key role in meeting future demand. As such, these plants will need to be evaluated for projects that will extend their useful life. Those projects might be targeted for efficiency improvements with coal as a fuel (burner upgrades, emissions control equipment, etc.) or as fuel-switch projects that take advantage of the benefits of natural gas.

Options

B&W PGG can perform an engineering study to help determine the best options for your specific application. Among the many options to consider are:

1. Fuel switch with modifications to the existing boiler
2. Fuel switch for the existing boiler and the addition of a gas turbine to the existing boiler cycle
   a. addition of simple cycle to the existing system
   b. hot windbox repowering
   c. combined cycle repowering
3. New combined cycle plant (elemental review) with retirement of the existing coal plant

Each option has advantages and disadvantages, including cost and operational considerations, including:

- comparison of modification costs vs. capital cost of a new gas turbine
- impact of future changes in fuel prices and the potential risk associated with natural gas price volatility
- life expectancy of gas turbines and heat recovery steam generators (HRSG) compared to steam boilers
- amount of acceptable de-rate

Since no two plants are identical, it is important that utilities work with an experienced supplier like B&W PGG to evaluate the best solutions for their needs.

1. Fuel Switch with Modifications to the Existing Boiler

The most obvious change to a power plant that switches from coal to gas will be the modifications to the fuel handling, storage and distribution equipment. The plant must receive natural gas via a pipeline spur from the local main transmission line. If a spur does not currently exist, the plant will need to evaluate the costs and activities (permits, land rights, etc.) associated with constructing a new spur. Once inside the plant perimeter, the gas must be metered and piped to the boilers, where new gas burners will be required (or to a new gas turbine if applicable).

If the existing boiler is modified for gas-firing, the convection pass, ducting and windbox will likely need modifications. The extent of the modifications will be determined by an engineering study that will look at overall furnace absorption, furnace exit gas temperature, and tube bank arrangement/material changes (superheater, reheater and economizer). Other operational changes like sootblowing schedules, attemperator spray flows, air heater operation and operation of any back-end emissions control equipment will need to be adjusted for the switch from coal to gas.

Technical Considerations

As B&W PGG studies your plant, we will evaluate the impact of the following technical considerations:

- characteristics of natural gas vs. original or current fuel
- impact on boiler design and capacity
- impact on cycle efficiency
- boiler and environmental equipment modifications
- burner modifications
- convection pass modifications
- changes to fans, ductwork, fluework, etc.
- amount of acceptable de-rate

Financial Considerations

Any modification to an existing plant carries considerable cost implications. This is true when upgrading a coal plant with new components for higher efficiency and/or lower emissions. Likewise, there are financial considerations for switching fuel from coal to natural gas. Cost ranges for modifications for the units shown in the comparison table below are estimated to be in the range of $50 to $75/kW.

The unique conditions of each plant will necessitate a detailed study of the potential operational options and their corresponding costs. These costs include only modifications to the boiler island. Excluded are costs related to bringing natural gas supply to the boiler.

2. Fuel Switch for the Existing Boiler with Addition of a Gas Turbine

Technical Considerations

The concept of repowering existing power plants is currently viewed as an option to economically meet new demands for improved efficiency, power growth and stricter environmental regulations. Partial repowering is the conversion of an existing site to combined cycle where the boiler and steam cycle are retained to the greatest extent possible. There are several major partial repowering alternatives. Many of these alternatives have multiple possible equipment configurations that can be considered depending on the option. Low gas turbine exhaust oxygen concentrations (as low as 12%), and high exhaust temperatures (exceeding 1100F) can provide design challenges depending on the combustion turbine used for this configuration.

2a. Addition of Simple Cycle to the Existing System

This technology uses the existing boiler and steam turbine equipment in essentially its original configuration. In

Comparison Table – Study Results of Typical Pulverized Coal to Natural Gas Conversions

Location	Ohio	Ohio	Oklahoma
Existing Unit Information			
– Year built	1954	1956	1981
– Original megawatts	152	103	390
– Operating pressure (PSI)	2,050	1,480	2,640
– Main steam temperature (F)	1,050	1,000	1,005
– Reheat outlet temperature (F)	1,000	1,000	1,005
– Original fuel	Pulverized bituminous coal	Pulverized coal	Pulverized coal
Target Performance Basis	100% NG with no pressure part changes	Minimize pressure part changes	Maintain 1005F w/excess air up to 87% MCR
Results and Limitations	Original maximum continuous rating; MCR (no limitations)	Maximum resulting SH temp = 950F; and Higher excess air for steam temperature control at lower loads	Cannot maintain steam temperature above 87% MCR without modifications; and Unable to fire 100% gas without pressure part modifications
Recommended Burner Modifications	Add gas elements	New low NO_X burners + OFA ports	New burners + NO_X ports
Recommended Pressure Part Modifications	Minimal to none required	Minimal to none required	Minimal to none required
Attemperator Recommendations	No changes required	No changes required	SH changes required
Fan Recommendations			
– Forced draft	Appears OK, evaluation by others	No changes required	Static capacity deficient
– Induced draft	Appears OK, evaluation by others	No changes required	No changes required
– Gas recirculation	Replace FGR fan and drive	No recommendations made	Removed from service
Air Heater Recommendations	No changes required	No changes required	Design static pressure deficient

this design, a gas turbine and feedwater heater are added in parallel to the existing boiler. Figure 1 provides a bullet summary and illustrates a typical equipment arrangement for this option. Depending on the specific plant configuration, balance-of-plant (BOP) material and erection services are required to complete this retrofit.

2b. Hot Windbox Repowering

In this configuration, a gas turbine is added to an existing plant and the exhaust from the turbine is ducted directly to the boiler windbox where it is used as combustion air for the boiler. The existing air heaters are typically retired with new stack gas coolers (or partial HRSG) added in parallel to the feedwater heaters to maximize cycle efficiency. Figure 2 provides a bullet summary and illustrates a typical equipment configuration for this technology.

Depending on the specific plant configuration, significant boiler and BOP material and erection services are required to complete these retrofits. This has been the repowering configuration of choice outside of the U.S. with Holland having more than 12 plants designed in this configuration (both retrofit and original). B&W PGG designed two new plants based on this cycle configuration in the early 1960s. Recent improvements in gas turbine technology have made integration of these machines with boilers more challenging than in the past.

2c. Combined Cycle Repowering

In this configuration, a gas turbine is added to an existing plant and the exhaust from the turbine is ducted to the boiler windbox where it is used as combustion air for the boiler. This configuration uses a supplemental heat exchanger (or partial HRSG) or mixes ambient air upstream of the boiler to cool the exhaust temperature to levels acceptable to existing windbox materials. The existing air heaters are typically retired with new stack gas coolers (or partial HRSG) added in parallel to the feedwater heaters to maximize cycle efficiency.

Figure 3 provides a bullet summary and illustrates a typical equipment configuration for this technology. Depending on the specific plant configuration, significant boiler and BOP material and erection services are required to complete this retrofit.

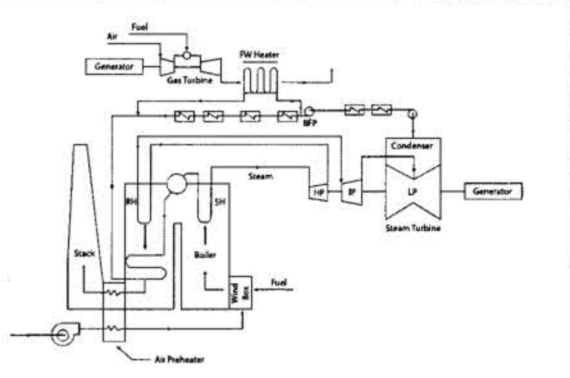

Fig. 1 Addition of Simple Cycle
- New gas turbine
- New recuperative feedwater heater(s)
- Retains steam system
  - » closes some extractions and feedwater heaters
- Advantages:
  - » low additional capital cost
- Disadvantages:
  - » small efficiency gain – 2% to 3%

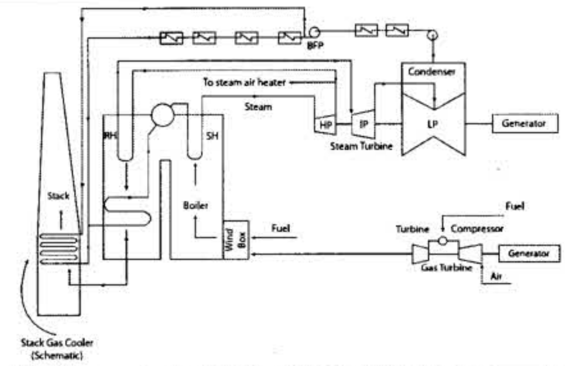

Fig. 2 Hot Windbox Repowering
- New gas turbine
- Retains boiler, steam turbine, generator, etc.
- Advantages:
  - » moderate power increase of up to 50%
  - » efficiency improvement of up to 15%
  - » retains current equipment and if desired, current fuel
  - » reduced emissions
- Disadvantages:
  - » requires new high temperature combustion air system
  - » may require boiler surface changes and/or de-rate
  - » requires special high temperature and low O_2 burners

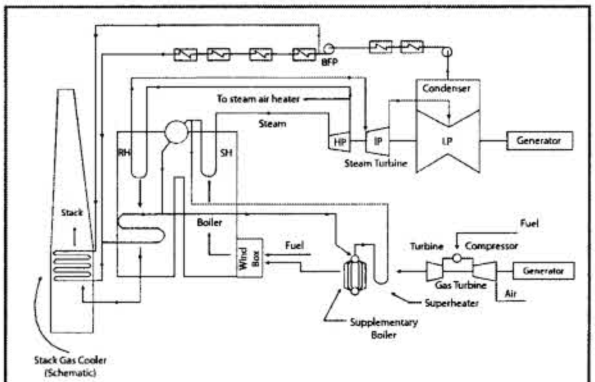

Fig. 3 Combined Cycle Repowering
- New gas turbine(s) and supplemental HRSGs or stack gas cooler
- Retains boiler, steam turbine, generator, etc.
- Advantages:
  - » moderate power increase of up to 70%
  - » efficiency improvement of up to 15%
  - » retains current equipment and if desired, current fuel
  - » reduced emissions
- Disadvantages:
  - » requires more complex steam system interface and piping systems
  - » may require boiler surface changes and/or de-rate
  - » requires special low O_2 burners

Financial Considerations

As the repowering configuration can vary significantly depending on the goals and constraints of a given system, cost for such a conversion can span a broad range. The combustion turbine will likely be the largest single component and cost. Estimates on retrofit costs range from $180 to $1,025 per unit kW increase in power.

3. New Combined Cycle Plant with Retirement of the Existing Coal Plant

A modern, highly efficient combined cycle plant is always a consideration when evaluating a fuel switch from coal to gas, especially when a considerable increase in power generation is needed. The higher capital cost of this option requires a careful analysis of its suitability to the unique needs of each utility.

This report is not intended to review every factor related to switching from coal to natural gas, but it is important for each prospective utility to consider the hidden costs associated with the retirement of a coal plant, including the cost of decommissioning or mothballing, as well as any site remediation costs. It is only when all the true costs are identified that the real savings from a fuel switch can be fully and properly evaluated.

Summary

Babcock & Wilcox Power Generation Group has the experience and expertise to help utility customers evaluate the operational, technical and financial considerations associated with a potential fuel switch from coal to natural gas. As plant owners consider their options, B&W PGG can assist in the evaluation of site-specific conditions and provide recommendations that represent the optimal balance of cost, schedule, performance and long-term availability.

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Proposed Adjustment for the 2015 Depreciation Study

Exhibit BCA-3

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description		Adjust Depreciation Expense - 2015 Study
	Electric Operating Revenues		
1.	Revenues from Base Rates		$ -
2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense		-
8.	Maintenance		-
9.	Subtotal		-
10.	Depreciation and Amortization	**EAB_WP32DR page 2 [A]**	52,074
11.	Amortization of Gain		-
12.	Administrative and General		-
13.	Other Taxes		-
14.	Total Other Operating Expense		52,074
15.	Operating Income Before Income Tax		(52,074)
16.	Interest Expense		-
17.	Taxable Income		(52,074)
18.	Current Income Tax Rate -	38.10% (Line 15 * 38.1%)	(19,840)
19.	Operating Income (line 15 minus line 18)		$ (32,234)

Adjustment to Test Year operations to reflect depreciation expense based on the 2015 depreciation study as adjusted by Brian Andrews.

Proposed Adjustment for the 2015 Depreciation Study

Exhibit BCA-3

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description		Adjust Depreciation Expense - 2015 Study
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2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense		-
8.	Maintenance		-
9.	Subtotal		-
10.	Depreciation and Amortization	**EAB_WP32DR page 2 [A]**	52,074
11.	Amortization of Gain		-
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